DIRECT TESTIMONY OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2018-2-E

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph M. Lynch and my business address is 220 Operation Way, Cayce, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by SCANA Services, Inc. as Manager of Resource Planning.

Q. PLEASE DESCRIBE YOUR DUTIES RELATED TO RESOURCE PLANNING IN YOUR CURRENT POSITION.

A. I am responsible for managing the department that produces South Carolina Electric & Gas Company's ("SCE&G" or "Company") forecast of energy, peak demand, and revenue. I also am responsible for developing the Company's generation expansion plans and overseeing the Company's load research program.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA, and a Ph.D. in management science and finance. I was employed by SCE&G as Senior Budget Analyst in 1977 to develop econometric models to forecast sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have testified on a number of occasions before this Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss SCE&G's avoided costs for power purchases under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). The short-run avoided costs for qualifying facilities ("QFs") that have power production capacity less than or equal to 100 kilowatts ("kW") are set forth in Rate

Schedule PR-1 attached to Witness Rooks' testimony as Exhibit Nos. __ (AWR-13) and __ (AWR-14). The long-run avoided costs for solar QFs that have production capacity greater than 100 kW and less than or equal to 80 megawatts ("MW") are set forth in Rate Schedule PR-2 attached to the Direct Testimony of Company Witness Allen Rooks as Exhibit Nos. __ (AWR-15) and __ (AWR-16). I also discuss the 11 components contained in the net energy metering ("NEM") methodology approved by the Commission in Order No. 2015-194 issued in Docket No. 2014-246-E.

AVOIDED COSTS UNDER PURPA

Q. WHAT DOES PURPA REQUIRE?

A. PURPA and its implementing regulations require electric utilities, including SCE&G, to purchase electric energy from qualifying small power production facilities and QFs at the utilities' avoided costs. However, state public utility commissions, such as the Commission, determine the method for calculating avoided costs.

Q. WHAT ARE AVOIDED COSTS?

A. PURPA regulations define "avoided costs" as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source." 18 C.F.R. § 292.101(b)(6). The Federal Energy

Regulatory Commission ("FERC") further recognizes that avoided costs include two components: "energy" and "capacity." Specifically, "[e]nergy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities." *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of* 1978, Order No. 69, 45 Fed. Reg. 12,214, 12,216 (Feb. 25, 1980) ("Order No. 69"). In Order No. 81-214 and subsequent decisions, the Commission has recognized that utilities are entitled to recover their avoided costs under PURPA.

Q. WHAT APPROACH DOES SCE&G TAKE TO CALCULATE THE ENERGY AND CAPACITY COMPONENTS OF AVOIDED COSTS?

A. As approved by the Commission in Order No. 2016-297, SCE&G uses a difference in revenue requirements methodology to calculate both the energy component and the capacity component of its avoided costs. This approach follows directly from PURPA's definition of avoided costs in that it involves calculating the revenue requirements between a base case and a change case. The base case is defined by SCE&G's existing fleet of generators and the hourly load profile to be supplied by these generators. The change case is the same as the base case except that the hourly loads are reduced by a 100 MW profile, which is the maximum reduction required by PURPA regulation 18 C.F.R. § 292.302(b)(1) for utilities with systems larger than 1,000 MW of generation such as SCE&G. Using a carefully constructed computer program called PROSYM, which models the commitment and dispatch of generating units to serve load hour-by-hour, SCE&G estimates the production costs that result from serving the base case load. A change case is derived from the base case by subtracting an appropriate 100 MW power purchase profile. Then, as with the base case, PROSYM is used to estimate the production costs that result from serving the change case. The avoided energy cost is simply the difference between the base case costs and the change case costs. The avoided capacity cost is the difference between the incremental capacity costs in both its base resource plan and the change plan.

Q. WHAT PERIOD OF TIME DOES THE COMPANY USE TO CALCULATE ITS AVOIDED COSTS?

A. The short-run avoided energy costs are calculated for the period May 2018 through April 2019. The long-run avoided costs are calculated for calendar years 2018 through 2032, which is the time period appropriate for SCE&G's 2018 15-year Integrated Resource Plan ("IRP") planning horizon pursuant to S.C. Code Ann. § 58-37-40. These 15-years are divided into three groups of five years each: 2018-2022, 2023-2027, and 2028-2032.

Q. WHAT IS SCE&G'S CURRENT RESOURCE PLAN?

A. SCE&G's current resource plan is attached as Exhibit No. __ (JML-1).

Q. WHAT IS SCE&G'S CURRENT RESERVE MARGIN POLICY USED IN DEVELOPING THIS RESOURCE PLAN?

A. Table 1 below summarizes SCE&G's reserve margin policy.

Table 1
Minimum Reserve Margin as Percent of Seasonal Peak Demand

	SUMMER	WINTER
Base Level	12%	14%
Peaking Level	14%	21%
Increment for Peaking	2%	7%

SCE&G has determined that during the months of May through October, which are grouped as "SUMMER", it needs resource reserves of at least 14% of the projected summer peak demand to serve reliably during peak times and at least 12% during the remaining periods. Likewise, for the months of November through April grouped as "WINTER", SCE&G needs a minimum of 21% of its projected winter peak demand to serve reliably during winter peak periods and at least 14% during the remaining periods. More details can be found in SCE&G's Reserve Margin Study which is attached as Exhibit No. __(JML-2).

Q. WILL SCE&G FILE THIS RESOURCE PLAN WITH THE COMMISSION AS PART OF ITS 2018 IRP FILING?

A. That is SCE&G's present intention. However, it is worth mentioning that the resource plan is only a plan, and not necessarily a decision. SCE&G therefore reserves the right to make changes as may be warranted or required by new or changed circumstances.

Q. IS SCE&G PROPOSING CHANGES TO ITS PR-1 AND PR-2 RATES?

A. Yes. As I will further discuss in more detail below, SCE&G proposes to limit the availability of its PR-2 Rate to solar QFs only and to offer separate rates for solar and non-solar QFs in its PR-1 Rate. SCE&G also proposes to its update PR-2 Rate going forward only on an "as needed" basis instead of twice a year.

PR-2 RATE

Q. WHY IS SCE&G PROPOSING TO LIMIT THE PR-2 RATE TO SOLAR QFs?

A. SCE&G must separate solar QFs from non-solar QFs in order to pay each type of QF the correct avoided costs. As more and more solar generation facilities interconnect with SCE&G's system, the benefit of each additional solar generation facility to the Company's system is diminished. SCE&G performed a study titled "Avoided Energy Cost Methods Study for Solar QFs" ("Methods Study") to measure this effect and it is attached to this testimony as Exhibit No. __ (JML-3).

The Methods Study demonstrates that if SCE&G does not distinguish its pricing between solar and non-solar QFs, then the amount SCE&G and its customers would be paying for solar energy would be more than the Company's actual avoided costs, which is contrary to the explicit intent of PURPA.

Q. WHAT SPECIFICALLY IS THE DIFFERENCE BETWEEN SCE&G'S TRADITIONAL ROUND-THE-CLOCK METHODOLOGY AND ITS SOLAR METHODOLOGY?

A. The avoided costs in the PR-2 rate are calculated over the 15-year IRP planning horizon and the avoided energy costs are divided into 3 five-year periods with the energy costs levelized within each period. As mentioned previously, SCE&G's avoided costs are calculated based on the difference in revenue requirements between a base case and a change case over this 15-year period.

Under the traditional methodology, the change case is derived from the base case by subtracting a 100 MW round-the-clock profile from the base case, i.e., 100 MWs are subtracted from every hour of the base case load profile. Avoided energy costs are then collected into four time periods composed of two seasons—peak season and off-peak season—and two daily periods—peak hours and off-peak hours. The peak season includes the months of June, July, August, and September. The peak hours during the peak season are 10:00 a.m. through 10:00 p.m. The peak hours for the off-peak season are 6:00 a.m. through 10:00 a.m. and 5:00 p.m. through 10:00 p.m. except during the months of May and October when they revert to the peak hours defined for the peak season. Using these four time-of-use periods results in four avoided energy costs, one for each time period.

Under the solar methodology, the change case is derived from the base case by subtracting a 100 MW solar profile from the base case. Because the solar distribution of energy is captured in the solar profile, avoided energy costs are not collected into separate time periods but simply added over all hours.

Q. HOW WAS THE METHODS STUDY STRUCTURED?

A. The Methods Study compared the traditional round-the-clock methodology and the solar methodology using the PROSYM model to estimate the difference in revenue requirements between the base case and three different change cases. The first change case used the round-the-clock 100 MW purchase. The second change case was derived using a power purchase from a 100 MW South Carolina solar profile. The third change case used a North Carolina solar profile to help determine the impact on avoided costs based on a different solar profile. Because PROSYM simulates random plant forced outages, the estimate of avoided energy costs could change simply by assuming a different set of forced outages. Therefore, for each case, the Company ran PROSYM 10 times, each time using a different random number seed to simulate a different set of plant forced outages, thus generating a slightly different avoided energy cost in each run. SCE&G then averaged the results of the 10 runs to determine the difference in revenue requirements.

Q. WHAT WERE THE CONCLUSIONS OF THE METHODS STUDY?

A. For each PROSYM simulation and for each year in the IRP planning period, SCE&G calculated the avoided energy costs, which are documented in the appendix to the Methods Study. The avoided energy costs were then levelized using present worth arithmetic and averaged over the 10 random seed runs. Table 2 below summarizes the calculations of the avoided energy costs under the round-the-clock profile case, which are also reflected on page 3 of the Methods Study.

Table 2
Avoided Energy Costs for Round-the-Clock Methodology

	Peak Season Peak Hours	**Peak Season Off-Peak Hours**	**Off-Peak Season Peak Hours**	**Off-Peak Season Off-Peak Hours**
Avoided Costs ($/MWH)	$36.27	$32.57	$35.82	$34.44
SC Solar Weights (kWh/kW)	470	287	672	682
Resulting Weighted-Average Avoided Cost Using SC Solar Weights				$35.03
Avoided Costs ($/MWH)	$36.27	$32.57	$35.82	$34.44
NC Solar Weights (kWh/kW)	496	299	580	612
Resulting Weighted-Average Avoided Cost Using NC Solar Weights				$35.02

Table 3 below compares the avoided costs of a solar generator using the round-the-clock 100 MW purchase methodology shown in Table 2 above with the avoided costs of a solar generator using the solar profile 100 MW purchase methodology, as also reflected on page 3 of the Methods Study.

Table 3
Avoided Cost Results Levelized

$/MWH	Round-the-Clock 100 MW Purchase	Solar Profile 100 MW Purchase	Difference
SC	$35.03	$30.18	$4.85
NC	$35.02	$30.86	$4.16

The results show that using the round-the-clock profile to develop the change case results in over-estimating the avoided energy costs by $4.85 per MWH. The avoided costs calculated based on the North Carolina profile are consistent with those of the South Carolina profile and therefore support these findings.

Q. WHY DOES ADDING SOLAR ENERGY TO THE SYSTEM RESULT IN REDUCING AVOIDED ENERGY COSTS BY $4.85 PER MWH?

A. As more and more solar is added to the system, the value of each additional increment of solar is reduced. One of the reasons for this diminishing value can be demonstrated by the so-called solar "Duck Curve." As shown in the graph on page 2 of the Methods Study, the Company's residual system load profile for many days of the year begins to reflect the silhouette of a duck as more solar is added to the system. Specifically, SCE&G's system first experiences a morning peak demand with little contribution from solar facilities. As the day progresses and solar facilities begin generating energy, SCE&G's residual system load profile experiences a steep ramping down of load to a bottom level of load followed by a steep ramping up in load to an afternoon or evening peak demand. In sum, the additional energy from solar generation causes the system to experience decreasing minimum loads between the morning and evening peak.

This curve creates operational problems in running the system as system operators have to select resources that can follow the load both down the curve and up the curve. Operational problems also occur under low load conditions because each generating unit has a minimum operating level below which it cannot be operated. If a baseload unit is taken off-line to prevent the system from over-generating during the low load conditions, then its capacity must be replaced during the ramping up period in order to serve the afternoon/evening peak. Additionally, some of the units that continue to operate to serve the low load must operate at an output level that is less efficient, i.e., more costly, than the optimum output level for which they were designed. Thus, while solar energy coming onto the system certainly has value, it also causes operational issues that result in positive variable integration costs that lower the avoided cost.

Q. IS SCE&G ABLE TO CAPTURE ALL THE VARIABLE INTEGRATION COSTS ASSOCIATED WITH THE OPERATIONAL ISSUES CAUSED BY THE INCREASED SOLAR ON THE SYSTEM?

A. No. The $4.85 per MWH lower avoided energy cost is calculated based on the expected commitment and dispatch of generating units needed to serve forecasted load hour-by-hour. Although this reduction reflects part of the variable energy costs associated with the addition of large amounts of solar to the system, it certainly does not capture all of these costs. Under real world conditions faced by system operators, the availability and operation of generators, the need to commit some units as standby extra capacity, the weather and load for the next day, the effect of clouds on solar facilities, and other similar constraints will always result in operational conditions that differ in some degree from the forecasts and estimates used in calculating the avoided energy costs. This uncertainty causes an increase in the Company's production costs.

Q. BASED ON THE COMPANY'S ANALYSIS, WHAT ARE SCE&G'S AVOIDED ENERGY COSTS FOR THE PR-2 RATE?

A. Table 4 below contains the avoided energy costs for the PR-2 rate.

Table 4
Solar QF Avoided Energy Costs ($/kWh)

Time Period	Annual
2018-2022	$0.02853
2023-2027	$0.02994
2028-2032	$0.03414

Q. HOW DOES SCE&G CALCULATE ITS AVOIDED CAPACITY COSTS RELATED TO SOLAR FACILITIES ON THE COMPANY'S PR-2 RATE?

A. SCE&G takes a similar approach to developing avoided capacity costs as it does with avoided energy costs. Using the difference in revenue requirements methodology approved by the Commission in Order No. 2016-297, SCE&G calculates the difference in the revenue requirement between the base case and the change case. Using the resource plan in its latest IRP or an updated resource plan if appropriate, SCE&G calculates the incremental capital investment related revenue required to support the existing resource plan. As with its calculation of avoided energy costs for solar, SCE&G derives a change case in its resource plan by considering the impact of a QF purchase from a 100 MW solar facility.

Q. USING THIS METHODOLOGY, WHAT ARE THE AVOIDED CAPACITY COSTS FOR THE PR-2 RATE?

A. SCE&G currently has over 700 MWs of solar capacity under Power Purchase Agreements ("PPAs") and the addition of another 100 MWs of solar has no effect on the resource plan. Stated differently, given the amount of solar generation that is currently projected to be interconnected to SCE&G's system, adding additional blocks of 100 MW of solar generation does not affect the Company's future capacity needs. For this reason, the avoided capacity costs of solar reflected in the PR-2 rate is zero.

Q. WHY DOESN'T ADDITIONAL SOLAR CAPACITY AFFECT SCE&G'S FUTURE CAPACITY NEEDS?

A. SCE&G performed a study that analyzed the impact of solar on its daily peak demands. This study titled "On Calculating the Capacity Benefit of Solar QFs ("Solar Capacity Benefit Study"), a copy of which is attached as Exhibit No. __ (JML-4), shows that, on more than 80% of the days during the winter months of

October through March, solar has no effect on SCE&G's daily peak demand. This is because the winter peak occurs either early in the morning before solar begins to generate energy or in the evening after solar is no longer generating. Table 5 below is an excerpt from the Solar Capacity Benefit Study. It shows the number of days by month that solar has no effect on the daily peak demand.

Table 5
Number of Days By Month When
Solar Has No Effect on the Peak Demand

	Amount of Solar Capacity Added to the System (MWs)			
Month	**200**	**500**	**800**	**1000**
1	27	27	27	28
2	19	23	24	25
3	23	26	27	29
4	8	13	20	22
5	3	6	7	7
6	0	0	0	0
7	0	0	0	0
8	0	0	2	3
9	2	2	5	6
10	15	20	25	26
11	21	22	23	24
12	21	23	23	24
Total	**139**	**162**	**183**	**194**

Since SCE&G's Reserve Margin Study shows that SCE&G needs as much capacity in the winter as it does in the summer, a resource has to provide capacity in the winter as well as the summer in order to avoid the need for capacity and thereby have capacity value. Because solar does not provide capacity during the winter period, the Company is unable to avoid any of its projected future capacity needs and, therefore, the avoided capacity cost of solar for these winter months is zero.

Q. TABLE 5 ALSO SHOWS THAT SOLAR IMPACTS THE DAILY PEAK ON MOST DAYS IN THE SUMMER AND ON ALL OF THE DAYS IN JUNE AND JULY. DID SCE&G ANALYZE THE IMPACT OF SOLAR ON THESE SUMMER DAYS?

A. Yes. This issue is also discussed in the Solar Capacity Benefit Study. Table 6 below, which is included on page 6 of the Solar Capacity Benefit Study, shows the impact of seven different solar farms, scaled up to 800 MWs on the five days of highest peak demand in the summer season. The farms are scaled to 800 MWs so as to approximate the over 700 MWs of solar capacity currently under PPAs plus the addition of another increment of 100 MWs whose impact is being reflected in avoided costs.

Table 6
5 Highest Summer Peak Days with 800 MWs of Solar

Solar Farm	No. of Days	Peak Reduction (MWs)	% Reduction	Last 100 MWs
Farm 1	5	313.8	39.2	24.5
Farm 2	5	273.8	34.2	24.7
Farm 3	5	223.4	27.9	15.6
Farm 4	5	340	42.5	21.4
Farm 5	5	262.5	32.8	11
Farm 6	5	204.1	25.5	17.7
Farm 7	5	310.2	38.8	21.9
Average	**5**	**275.4**	**34.4**	**19.5**

On average over the 5 peak days, an 800 MW solar facility can be expected to reduce the daily peak demand by approximately 34.4% in the summer season, which equates to approximately 275 MWs. The last 100 MWs of the 800 MWs has an incremental effect of about 19.5%, which is approximately 19.5 MWs.

The following table shows similar results for the remainder of the summer season.

Table 7
Remaining Days of the Summer Season with 800 MWs of Solar

Solar Farm	No. of Days	Peak Reduction (MWs)	% Reduction	Last 100 MWs
Farm 1	148	153.6	19.2	8.7
Farm 2	179	152.1	19	10.4
Farm 3	122	167.7	21	8.2
Farm 4	163	176.5	22.1	10.4
Farm 5	163	188.5	23.6	9.7
Farm 6	179	174.5	21.8	9.9
Farm 7	179	162.1	20.3	10.1
Average	**167.9**	**167.9**	**21.0**	**9.6**

Thus, 800 MWs of solar can be expected to reduce the daily peak demand on average over non-peak days approximately 21% with only 9.6% for the last 100 MWs. Because only the incremental values are relevant for avoided cost calculations, the last 100 MWs of solar will reduce the summer peak by about 19.5 MWs on peak days and 9.6 MWs on the rest of the days. This translates into a peak effect of approximately 9.9 MWs and a base effect of approximately 9.6 MWs. Considering this small impact in summer and no impact in winter, SCE&G is not able to reduce capacity additions in its resource plan and therefore there are no avoided capacity costs.

Q. WHY DOES SCE&G LIMIT ITS EVALUATION OF AVOIDED COSTS TO THE 15-YEAR PLANNING HORIZON OF ITS IRP?

A. It is important to recognize that future projections are uncertain. For avoided energy costs, it is not clear whether the projected costs over the last 5 years of the IRP planning horizon are too high or too low for those 5 years, let alone the 5 or 10 years beyond. Therefore, using projected costs beyond the 15-year planning horizon would be unreasonably speculative and would increase the costs borne by SCE&G's customers.

Q. HOW WILL SCE&G ADDRESS AVOIDED COSTS FOR NON-SOLAR QFs OF GREATER THAN 100 KW AND UP TO 80 MW?

A. SCE&G plans to negotiate contracts with any non-solar QF for which the PR-1 rate is not appropriate. In the past and prior to the development of the PR-2 rate, SCE&G for many years offered a PR-1 rate as well as an offer to negotiate a contract with any QF that did not qualify for the PR-1 rate. This response to PURPA worked satisfactorily for many years and SCE&G proposes to return to that arrangement for non-solar QFs of greater than 100 kW and up to 80 MW.

Q. WHY IS SCE&G ALSO PROPOSING TO UPDATE THE PR-2 RATE ONLY ON AN "AS NEEDED" BASIS INSTEAD OF TWICE A YEAR?

A. Avoided costs are based on projections of load, resource needs, fossil fuel prices, etc., over the IRP planning horizon. If the avoided costs do not change significantly, then there is no need for an update. Instead, SCE&G believes it is more appropriate to update the PR-2 Rate only when there is a significant change in the avoided cost projections, or more specifically, when the Company's long run avoided costs change significantly.

<u>PR-1 RATE</u>

Q. WHAT MODIFICATIONS TO THE PR-1 RATE IS SCE&G PROPOSING?

A. As discussed previously, SCE&G proposes to have separate rates for solar QFs and non-solar QFs both with capacities up to and including 100 kW.

Q. WHY IS SCE&G PROPOSING TO HAVE SEPARATE PR-1 RATES FOR SOLAR QFs AND NON-SOLAR QFs?

A. For the same reasons I discussed previously regarding the PR-2 rate, SCE&G must separate solar QFs from non-solar QFs in order to pay each type of QF the correct avoided costs. As reflected in the Methods Study, the benefit of each additional solar generation facility to the Company's system is diminished as more and more solar generation facilities interconnect with SCE&G's system. If SCE&G does not distinguish its pricing between solar and non-solar QFs, then the amount SCE&G and its customers would be paying for solar energy would be more than the Company's actual avoided costs, which is contrary to the explicit intent of PURPA.

Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT FOR SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. SCE&G uses the same methodology to estimate avoided energy costs for solar QFs on PR-1 as it did for solar QFs on PR-2. The only difference is the time period over which the avoided energy costs are estimated. The short-run avoided energy costs in the PR-1 rate are calculated for the period May 2018 through April 2019.

Q. WHAT IS THE AVOIDED CAPACITY COST COMPONENT FOR SOLAR QFs IN THE PR-1 RATE?

A. The avoided capacity cost for solar QFs subject to the PR-1 rate is zero. As explained with respect to the PR-2 rate, incremental solar QFs do not affect the resource plan and therefore avoid no future resources or their cost.

Q. HOW DOES SCE&G COMPUTE THE AVOIDED ENERGY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. As discussed previously, SCE&G uses PROSYM to estimate the change in production costs that result from serving the base case load and the change case. The change case for non-solar QFs is derived from the base case by subtracting a 100 MW round-the-clock power purchase profile. The avoided costs are then accumulated into the four time-of-use periods described above. A non-solar QF would be paid based on how much energy it produces in each of these four time-of-use periods.

Q. HOW DOES SCE&G COMPUTE THE AVOIDED CAPACITY COMPONENT FOR NON-SOLAR QFs SUBJECT TO THE PR-1 RATE?

A. Normally SCE&G would calculate its avoided capacity costs by taking the difference in avoidable costs between a base resource plan and a change case. However, because the PR-1 rate is designed for small QFs with a capacity rating of up to 100 kWs, SCE&G does not believe there will ever be enough capacity from these small non-solar QFs to affect its resource plan and, therefore, the avoided capacity costs for PR-1 are zero.

Q. IS SCE&G PROPOSING OTHER CHANGES TO THE PR-1 RATE FOR NON-SOLAR QFs?

A. Yes. Previously, SCE&G defined two “critical peak hour” periods and used the number of hours in these periods to convert the annual capacity cost from $ per kW-year into $ per kWh. SCE&G proposes to eliminate the critical peak hours as a way to credit QFs for their capacity value for several reasons. First, these critical peak hours were established to accommodate solar facilities. Since SCE&G must use a solar profile to calculate solar related avoided costs, it is more appropriate to simply add an avoided capacity credit to the avoided energy cost to deliver the capacity value to a solar QF. Second, the addition of so much solar on SCE&G’s system shifts the Company’s previously experienced effective peak hour—the hour that the residual load (system load minus solar generation) peaks. This can be readily seen in the graph on page 2 in Exhibit JML-4. Because of this solar effect, it is inappropriate to look only to certain hours selected from past experience in which to pay out a capacity credit. Finally, as reflected in the Reserve Margin Study and in Table 1 above, SCE&G has determined that, during the months of May through October ("SUMMER"), the Company needs resource reserves of at least 14% of the projected summer peak demand during peak times, and at least 12% during the remaining periods to reliably serve its customers. For the months of November through April ("WINTER"), SCE&G needs a minimum of 21% of its projected winter peak demand during peak times and at least 14% to serve the load during the remaining periods. Since SCE&G's need for capacity spans the entire year, it is necessary to spread avoided capacity costs throughout the year to reflect the Company's reliability risk as explained in the Reserve Margin Study.

Q. WHAT ADJUSTMENTS ARE MADE TO THE AVOIDED COSTS IN THE PR-1 RATE?

A. The avoided energy cost results for both solar QFs and non-solar QFs are adjusted for line losses, working capital impacts, gross receipts taxes, and generation taxes. The Company made no adjustments to the avoided capacity costs for both solar and non-solar QFs under PR-1 because these costs are zero.

Q. WHAT IS THE RESULTING PR-1 RATE?

A. The avoided energy costs are shown in Table 8 below.

Table 8

PR-1 RATE: AVOIDED ENERGY COST
Non-Solar QFs ($/kWh)

Time Period	**Peak Season Peak Hours**	**Peak Season Off-Peak Hours**	**Off-Peak Season Peak Hours**	**Off-Peak Season Off-Peak Hours**
May-April	$0.03233	$0.02886	$0.03445	$0.03298

Solar QFs ($/kWh)

Time Period	**Year Round**
May-April	$0.03256

The avoided capacity costs for solar and non-solar QFs are zero.

COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES

Q. WHAT ARE THE COMPONENTS OF VALUE FOR NEM DISTRIBUTED ENERGY RESOURCES?

A. By way of its Order No. 2015-194 issued in Docket No. 2014-246-E, the Commission approved the following 11 components of value for NEM Distributed Energy Resources:

Net Energy Metering Methodology

1. +/- Avoided Energy
2. +/-Energy Losses/Line Losses
3. +/- Avoided Capacity
4. +/- Ancillary Services
5. +/- T&D Capacity
6. +/- Avoided Criteria Pollutants
7. +/- Avoided CO_2 Emission Cost
8. +/- Fuel Hedge
9. +/-Utility Integration & Interconnection Costs
10. +/- Utility Administration Costs
11. +/- Environmental Costs

= Total Value of NEM Distributed Energy Resources

In Docket No. 2017-2-E, the Company calculated the value for these components and, in Order No. 2017-246, the Commission determined that those values complied with the NEM Methodology approved by the Commission in Order No. 2015-194. Table 9 below shows the components of value of NEM Distributed Energy Resources approved by the Commission in Order No. 2017-246.

Table 9
Total Value of NEM Distributed Energy Resources ($/kWh)
Approved in Order No. 2017-246

	Current Period	**IRP Planning Horizon (15-Year Levelized)**	**Components**
1	$0.03273	$0.03199	Avoided Energy Costs
2	$0	$0.00172	Avoided Capacity Costs
3	$0	$0	Ancillary Services
4	$0	$0	T & D Capacity
5	$0.00004	$0.00004	Avoided Criteria Pollutants
6	$0	$0	Avoided CO_2 Emission Cost
7	$0	$0	Fuel Hedge
8	$0	$0	Utility Integration & Interconnection Costs
9	$0	$0	Utility Administration Costs
10	$0	$0	Environmental Costs
11	$0.03277	$0.03375	Subtotal
12	$0.00268	$0.00276	Line Losses @ 0.9245
13	$0.03545	$0.03651	**Total Value of NEM Distributed Energy Resources**

Q. HAS SCE&G UPDATED THESE COMPONENTS OF VALUE?

A. Yes. Table 10 shows the updated components of value for NEM Distributed Energy Resources. Two columns of numbers are shown: one for the current value and one for the value over the IRP planning horizon. The difference between these two columns of numbers represents the future benefits of DER and are subject to recovery under S.C. Code Ann. § 58-40-20(F)(6).

Table 10
Total Value of NEM Distributed Energy Resources ($/kWh)

	Current Period	IRP Planning Horizon (15-Year Levelized)	Components
1	$0.03070	$0.03010	Avoided Energy Costs
2	$0	$0	Avoided Capacity Costs
3	$0	$0	Ancillary Services
4	$0	$0	T & D Capacity
5	0.00008	$0.00008	Avoided Criteria Pollutants
6	$0	$0	Avoided CO_2 Emission Cost
7	$0	$0	Fuel Hedge
8	$0	$0	Utility Integration & Interconnection Costs
9	$0	$0	Utility Administration Costs
10	$0	$0	Environmental Costs
11	$0.03078	$0.03018	Subtotal
12	$0.00251	$0.00246	Line Losses @ 0.9245
13	$0.03329	$0.03264	**Total Value of NEM Distributed Energy Resources**

Q. PLEASE EXPLAIN THE COMPONENTS OF VALUE FOR AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS SHOWN ON LINE NOS. 1 AND 2 OF TABLE 10.

A. The components of value for avoided energy costs and avoided capacity costs are based on the PURPA avoided cost values previously discussed with one adjustment. The avoided energy costs are adjusted to remove the cost of criteria pollutants, which is then reflected in the component shown on Line 5, Avoided Criteria Pollutants.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ANCILLARY SERVICES SHOWN ON LINE NO. 3 OF TABLE 10.

A. Ancillary services refer to the need to balance the load and generation on the system and include operating reserves, both spinning and non-spinning; frequency regulation; and voltage control. SCE&G expects that the cost of providing these ancillary services will increase with the addition of large amounts of solar energy. Currently, however, at the relatively small amount of NEM Distributed Energy Resources generation, SCE&G has again assigned a value of zero to ancillary services as it did in Docket No. 2016-2-E.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR TRANSMISSION AND DISTRIBUTION CAPACITY SHOWN ON LINE NO. 4 OF TABLE 10.

A. SCE&G's NEM distributed resources do not avoid transmission or distribution capacity and therefore the value of this component is zero. On SCE&G's transmission system, customer-scale NEM resources are distributed across SCE&G's transmission system and have too small of an impact on any transmission circuit to result in avoided transmission capacity. For example, the most impacted substation currently on SCE&G's system is connected to 1,368 kW of solar capacity owned by 178 customers. The impact of a 1,368 kW change in load is much too small to affect the planning of or need for a 115 kV or a 230 kV circuit, which carry loads between 237,000 and 948,000 kWs.

On the distribution system, SCE&G's engineers must design a circuit for circumstances that will stress the circuit. In particular, since solar output is intermittent during the day and non-existent at night, they must also plan for when the DER is not supplying power. The distribution line must carry the load both when the DER is generating and when it is not because of weather related factors or because DER resources are off line.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CRITERIA POLLUTANTS SHOWN ON LINE NO. 5 OF TABLE 10.

A. SCE&G associates a positive avoided cost value to criteria pollutants such as NO_x and SO_2. The avoided cost of these pollutants typically is included in the Company's avoided energy costs but, as I mentioned previously, these costs have been separated out in this proceeding for reporting purposes.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR AVOIDED CO_2 POLLUTANTS SHOWN ON LINE NO. 6 OF TABLE 10.

A. Pursuant to Commission Order No. 2015-194, the component of value for avoided CO_2 is set at zero until state or federal laws or regulations result in an avoidable cost on utility systems for these emissions. Currently, there are no state or federal laws or regulations restricting the emission of CO_2 pollutants and, therefore, the value for CO_2 pollutants is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR FUEL HEDGE SHOWN ON LINE NO. 7 OF TABLE 10.

A. SCE&G does not hedge fuels for electric generation. Therefore, the value for fuel hedging is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY INTEGRATION & INTERCONNECTION COSTS SHOWN ON LINE NO. 8 OF TABLE 10.

A. At present, the integration and interconnection costs of NEM Distributed Energy Resources are being collected through a DER rider added to the fuel clause. Therefore, the value of this component is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR UTILITY ADMINISTRATION COSTS SHOWN ON LINE NO. 9 OF TABLE 10.

A. At present, the administration costs of NEM Distributed Energy Resources are being collected through a DER rider being added to the fuel clause. Therefore, the value of this component is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENVIRONMENTAL COSTS SHOWN ON LINE NO. 10 OF TABLE 10.

A. The component of "Environmental Costs" refers to any appropriate environmentally related costs that were not already included in other net metering methodology components. At present, there are no environmental costs that are not already included in the other specific components of the methodology. Therefore, the value of this component is zero.

Q. PLEASE EXPLAIN THE COMPONENT OF VALUE FOR ENERGY LOSSES/LINE LOSSES SHOWN ON LINE NO. 11 OF TABLE 10.

A. When a NEM Distributed Energy Resource serves a customer's load behind their meter or when it puts power onto the distribution system, SCE&G avoids having to generate that specific amount of energy. The Company also avoids the energy required to bring the power to the customer's meter or the distribution system, i.e. the line losses associated with delivering power across the system. The loss factor used for these NEM values represents the cumulative marginal line losses at a residential customer's meter.

<u>CONCLUSION</u>

Q. WHAT IS SCE&G REQUESTING OF THE COMMISSION IN THIS PROCEEDING?

A. SCE&G respectfully requests that the Commission 1) approve the Company's proposed PR-1 and PR-2 Rates; 2) approve the total value of NEM Distributed Energy Resources; 3) approve the costs incurred by the Company in providing DER programs during the Review Period as being reasonable and prudent; and 4) find that the Company's fuel purchasing practices were reasonable and prudent for the Review Period.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.